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ANALYSIS OF UTILITY CONTROL STRATEGIES USING THE LIMB TECHNOLOGY

by:

T. E. Emmel
RADIAN CORPORATION
RESEARCH TRIANGLE PARK, NORTH CAROLINA 27709

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68-02-3994 (W. A. 28)

and

B. A. Laseke
PEI ASSOCIATES, INC.
CINCINNATI, OHIO 45246

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EPA Project Officer

Norman Kaplan
U. S. ENVIRONMENTAL PROTECTION AGENCY
AIR AND ENERGY ENGINEERING RESEARCH LABORATORY
RESEARCH TRIANGLE PARK, NORTH CAROLINA 27711

AIR AND ENERGY ENGINEERING RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

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16. ABSTRACT The report gives results of an evaluation of the impact of proposed acid rain legislation on the potential application of limestone injection multistage burner (LIMB) technology incorporating recent research and development findings. (NOTE: Several bills were proposed by the 97th and 98th Congress, requiring reduction of acid rain precursor emissions, utilizing different mixes of emission control technologies to achieve SO2 and NOx reductions at coal-fired utility power plants.) Several regulatory strategies and emission reduction targets were developed. For each regulatory strategy developed, the control technology mix of LIMB, flue gas desulfurization (FGD), and coal switching required to achieve the selected emission reduction level was determined. Next, the maximum number of boilers to which LIMB technology could be applied was determined by examining technical and regulatory constraints and emission reduction targets. The cost effectiveness of each regulatory case and control technology mix was estimated to evaluate the cost of each control technology mix. The study found that proposed acid rain legislation which mandates the retrofit of high efficiency control technologies such as FGD or which requires national SO2/NOx reduction levels greater than 10 million tons per year would significantly reduce the application of LIMB.

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Limestone	Rain	Stationary Sources	08G	04B
Utilities	Acidification	Limestone Injection Multistage Burner (LIMB)		07B, 07C
Coal	Sulfur Dioxide		21D	
Combustion	Nitrogen Oxides	Acid Rain	21B	
Emission	Flue Gases Desulfurization	Coal Switching	14G	07A

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ABSTRACT

A number of bills have been proposed by Congress that would require reductions of acid rain precursor emissions. These congressional bills would require different mixes of emission control technologies to achieve SO_2 and NO_x reductions at coal-fired utility power plants. The objective of this research program was to evaluate the impact of proposed acid rain legislation on the potential application of LIMB technology incorporating recent LIMB research and development findings. This research was conducted jointly by Radian Corporation and PEI Associates.

A number of regulatory strategies and emission reduction targets were developed by reviewing the acid rain legislation that had been proposed in the 97th and 98th congressional sessions. For each regulatory strategy developed, the control technology mix of LIMB, FGD, and coal switching required to achieve the selected emission reduction level was determined. Next, the maximum number of boilers to which LIMB technology could be applied was determined by examing technical and regulatory constraints and emission reduction targets. The cost effectiveness of each regulatory case and control technology mix was estimated to evaluate the cost each control technology mix.

The study found that proposed acid rain legislation which mandates the retrofit of high efficiency control technologies such as FGD or which requires national SO_2/NO_x reduction levels greater than 10 million tons per year would significantly reduce the application of LIMB. For those regulatory strategies which do not mandate the use of FGD and which require emission reductions of between 8 to 10 million tons per year, the potential LIMB application ranges from 15,000 MW to 100,000 MW of coal-fired boiler capacity in the 31 eastern state acid rain region.

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SECTION 1
INTRODUCTION

A number of bills have been proposed by Congress that would require reductions of acid rain precursor emissions. These bills propose strategies that focus on the reduction of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from the combustion of fossil fuels in electric utility power-generating plants. To achieve the necessary emission reductions would require that a majority of these reductions be made at existing coal-fired electric utility power plants which contribute over 60 percent of the nationwide SO_2 emissions.

The many congressional bills differ in the mix of likely emission control technologies used to achieve SO_2 and NO_x reductions. For example, one bill mandates the use of flue gas desulfurization systems by requiring older boilers to comply with the 1979 New Source Performance Standards at the largest SO_2 emitting utility power plants.

Control technologies likely to be employed at coal-fired power plants include: coal switching, physical coal cleaning, flue gas desulfurization (FGD), and limestone injection multistage burner (LIMB). Researchers have investigated these specific control technologies with respect to their overall efficacy to reduce the emission of acid rain precursors from coal-fired utility boilers. These researchers have focused on the emission reduction potential and cost impacts associated with particular strategies. As one of these control technologies, LIMB has received interest because it can be easily retrofit to older boilers, and because of its relatively low cost, simultaneous SO_2 and NO_x reduction, and competitive cost per unit of pollutant removed. These advantages compare favorably to the disadvantages associated with the other control strategies; namely - negative localized economic impacts associated with coal switching, emission reduction uncertainties of coal washing due to coal quality variability, and the high costs and spatial constraints associated with retrofitting FGD to existing boilers.

To date, LIMB has not been rigorously evaluated with respect to the following: recent, significant advances in the technology, suitability to particular categories of boilers, suitability to specific types of boilers, retrofit capability, capital costs, annual revenue requirements, SO_2 reduction, and corresponding NO_x reductions. The objective of this research program was to evaluate the impact of the various types of proposed acid rain legislation on the potential application of the LIMB technology, while considering recent LIMB research and development findings.

TECHNICAL APPROACH

Four specific tasks were conducted by Radian Corporation and PEI Associates under this program effort:

- Identify the major types of legislative/regulatory cases,
- Develop boiler specific data base,
- Evaluate the applicability of LIMB based on technical constraints for each legislative/regulatory case selected,
- Estimate control costs for each control technology mix selected for each regulatory case.

The study bases were developed at the outset by reviewing the acid rain bills proposed in the 97th and 98th congressional sessions. This review determined what utility boiler population should be the focus of the study and what regulatory framework should be applied to this boiler population. Additionally, the results of other similar studies were evaluated so that this study effort would be consistent for comparative purposes. The results of this task identified four regulatory cases which provided the focus of this study. Section 2 of this report discusses the results of the legislative/regulatory case development.

For each regulatory case, the control technology mix of LIMB, FGD, and coal switching required to achieve the selected emission reduction level was determined. Technology applicability criteria were developed for each of the control technologies based on coal sulfur content, boiler age, and boiler firing type. Section 3 of this report presents the control technology performance and boiler applicability bases used in this study.

The maximum number of boilers to which LIMB technology could be applied was based on technical and regulatory constraints and emission reduction targets. Several sensitivity cases were developed to evaluate the impact of using coal switching versus LIMB at boilers where both could be applied. The cost effectiveness of each regulatory case and control technology mix was estimated and then used to evaluate the cost of the control technology mix.

LIMB and FGD costs were developed by PEI Associates using the Integrated Air Pollution Control System - Version II computer model. This computer model, recently developed for EPA by PEI, provided specific cost estimates for each coal fired boiler using 1980 boiler specific parameters (coal sulfur level, capacity factor and size, etc.). The cost of coal switching was based on an assumed fuel price differential of $1.00 per million Btu between the currently used coal and a 2.5 pounds of SO_2 per million Btu eastern bituminous coal.

CONCLUSIONS

The study results and conclusions are discussed in Section 4. The study found that acid rain legislation which mandates new source performance levels of control on existing boilers or which requires national SO_2/NO_x reduction levels greater than 10 million tons per year would significantly reduce the application of LIMB. For those regulatory strategies which do not require state/boiler specific SO_2 reductions greater than 70% or which require emission reductions of 8 to 10 million tons per year, the potential LIMB applicability was up to 100,000 MW of coal-fired boiler capacity in the 31 eastern state acid rain region.

These results are consistent with other studies and indicate that mandating high state/boiler level SO_2 reductions significantly increases the cost of SO_2 control to the consumer by requiring a very high level of emission control at most coal-fired boilers, resulting in a greater use of FGD.

SECTION 2
REGULATORY CASE AND DATA BASE DEVELOPMENT

Numerous bills have been proposed in both houses of Congress which would mandate significant reductions of acid rain precursors. Almost all of these bills would require significant reductions of SO_2 from coal-fired utility power plants. However, each bill differs in how it would affect the mix of likely control technologies that would be used to achieve the necessary reductions and the geographic region impacted by the legislation. Table 2-1 summarizes the major features of each bill reviewed as it relates to this study. The following sections discuss the legislative analysis and regulatory case development and the utility boiler data base development.

REGULATORY CASE DEVELOPMENT

The primary differences in the bills are a result of the level of SO_2 reductions that is required at each plant due to plant/boiler specific emission limits or due to requiring high overall SO_2 reduction levels. All of the bills use 1980 as the base year for which emission reduction levels apply. Differences in the method of calculating excess emissions, implementation years, financing methods and state reduction allocation and implementation were not considered important for the purposes of this study. The following three legislative/regulatory cases were selected for study analysis:

Regulatory Case	SO_2 Reductions
Boiler Performance Standard	10 million tons/yr
Regional Reduction Levels	10 million tons/yr
Regional Reduction Levels	8 million tons/yr

For this study, a regulatory strategy was developed based on those bills which base reductions on boiler and/or state reduction performance standards (S. 1709, HR 4816, HR 3400). These bills require that existing boilers must comply with New Source Performance Standards (1971 or 1979) if their emissions are greater than a specified amount of SO_2 per million Btu of fuel. Additionally, these bills also require state wide reductions.

TABLE 2-1. REGULATORY FRAME WORK OF PROPOSED ACID RAIN LEGISLATION

Title of Legislation	Congress	Impact Region	Reduction Requirements	Reduction Approaches Permitted	NO_x Credit	Reference
Mitchell Bill (S. 1706)	97th	31 Eastern States	10 MT/yr below 1980. Allocated based on emissions in excess of 1.2 lb SO_2/10^6 BTU	No restrictions on method of achievement and regional trading	2 units of NO_x to 1 unit SO_2	1
Moynihen Bill (S. 1709)	97th	31 Eastern States	Performance Standard: 1) Boilers with emissions > 3 lb SO_2/10^6 BTU - 85% Reduction 2) States with average emissions ≤ 2 lb SO_2/10^6 BTU need 50% reduction States with average emissions > 2 lb SO_2/10^6 BTU need 75% reduction	No restrictions on method of achievement and regional trading	2 units of NO_x to 1 unit of SO_2	1
D'Amours Bill (HR 4816)	97th	31 Eastern States	State reduction equal to: 1) 85% of 1980 level or attain an average level of 1.2 lb SO_2/10^6 BTU 2) All boilers > 100 MW must achieve 1.2 lb SO_2/10^6 BTU	No restrictions on method of achievement and regional training	No provisions	1
Moffett Bill (HR 4829)	97th	31 Eastern States	10 MT/yr below 1980. Allocated based on emissions in excess of 1.2 lb SO_2/10^6 BTU	No restrictions on method of achievement and regional trading	2 units of NO_x to 1 unit of SO_2	1
Committee Bill (S. 3041)	97th	31 Eastern States	8 MT/yr reduction from 1980 levels	No restrictions on method of achievement and regional trading	No credit	1

TABLE 2-1. (Cont.)

Title of Legislation	Congress	Impact Region	Reduction Requirements	Reduction Approaches Permitted	NO_x Credit	Reference
Waxman-Sikorski Bill (HR 3400)	98th	48 Continguous States	10 MT/yr reduction of SO_2 below 1980 levels and 4 MT/yr of NO_x to be allocated by each states combustion above 1.2 lb $SO_2/10^6$ BTU	Performance standard of 70-90% reduction at top 50 power plants with the remaining 3 MT/yr to be reduced by SIP's	NO_x to be reduced by tighter utility boiler NSPS and truck emission standards	2
Senate Environment & Public Works Bill (S. 768)	98th	31 Eastern States	10 MT/yr below 1980. Allocated by emissions in excess of 1.2 lb $SO_2/10^6$ BTU	Approach left up to SIP's with a default performance standard of 1.2 if states do not meet compliance	No provisions	3, 4
Glenn Bill (S. 2215)	98th	31 Eastern States	8 MT/yr below 1980 levels for electric utility power plants	Approach left up to SIP's but could restrict the use of coal switching in States where it causes significant negative economic impact and pays up to 90% of costs for hardware related control technologies	No provisions	5

Because these bills require very high levels of SO_2 reduction at individual plants/boilers, the use of wet flue gas desulfurization (FGD) will be required at most affected plants. These legislative cases are entitled "Boiler Performance" cases and FGD is applied to boilers at the largest emitting utility power plants.

The other major type of bill introduced into Congress (HR 4829, S 3041, S 1706, S 768, 3221 S) allocates state level emission reductions generally based on the portion of emissions from facilities with emission rates greater than 1.2 pounds of SO_2 per million Btu fuel input. These bills allow the states to determine how the allocated emission reductions for that state are to be achieved and in some cases allow trading of emission reductions. Because these bills provide much greater flexibility in how emission reductions are achieved on a plant/boiler basis, they do not require the use of certain types of SO_2/NO_x control technologies. Study cases based on these types of legislative scenarios are entitled "Regional Reduction" cases.

The other major difference between bills that would impact the mix of control technologies used by utilities is the amount of emission reduction required. This occurs because as the SO_2 reduction target increases, the average emission reduction needed to be achieved at each coal-fired boiler increases. For this study three SO_2 emission reduction levels were evaluated. The 8 and 10 million ton per year reduction levels were selected consistent with the different levels proposed by the congressional bills reviewed. A 12 million ton per year SO_2 reduction level was selected as a sensitivity case to evaluate the impact that this level of reduction would have on the control technology mix needed to achieve this high level of reduction.

The Congressional bills differ on the amount of credit given for NO_x reductions. For this study half credit was given for NO_x reductions: 1.0 ton of NO_x removed equals 0.5 tons of SO_2 reduction. Thus, for this study a NO_x credit was included for low NO_x combustion modification assumed to be made with furnace sorbent injection.

REGION AND BOILER SPECIFIC DATA BASE

One way in which the proposed acid rain bills differ is by applicable geographic region. Most bills aim for reductions in the "acid deposition impact region", which consists of the 31 eastern states. Because SO_2 emissions from the remaining 17 contiguous states are small, this study also focused on the 31 eastern state region.

All major bills would affect utility and industrial emitters of SO_2 beginning in the mid-1990's. This study assumed 1995 to be the year in which legislation would be fully in effect. This time frame was used to determine remaining boiler life and coincides with the expected commercial availability of the LIMB technology.

A major part of the study effort was the development of a boiler specific data base and boiler specific control costs for LIMB, FGD and coal switching. Developing an accurate data base for all coal-fired boilers in the 31 eastern states was not feasible. However, an accurate data base was easily developed for the top 100 SO_2 emitting coal-fired utility power plants. These top 100 plants accounted for over 72 percent of total U. S. utility power plant SO_2 emissions in 1980. The results of the applicability study for the top 100 plants was then extrapolated to the boilers in the 31 eastern state region based on an analysis conducted by PEI Associates that used data from the information sources presented on Table 2-2. The following table presents the SO_2 emission reduction targets used for each regulatory case based on allocating 72 percent of the emission reduction target to the top 100 coal-fired boiler population:

Regulatory Strategy	SO_2 Emission Reduction From Top 100 Plants (10^6 Tons Per Year)	Total Required SO_2 Reduction (10^6 Tons Per Year)
Boiler Perf. Standard	7.2	10
Regional Reduction	7.2	10
Regional Reduction	5.8	8
Regional Reduction	8.6	12

TABLE 2-2. SOURCES OF INFORMATION FOR DATA BASE DEVELOPMENT

Form	Description
Compliance Data System	Quarterly updated data collection for all emission sources (EPA). Excess emission data for all air pollution sources.
Edison Electric Institute	Annual, mandatory data collection of member utilities. Provides useful inventory data.
EIA-119M	Formerly, EP Form 119M. Monthly, mandatory data collection for 259 utilities. Provides data on system generation, receipts, deliveries, peak load, and capacity. Discontinued after 1983.
EIA-759	Formerly, FPC Form 4. Monthly, mandatory data collection for 814 utilities. Provides net generation, fuel consumption, and end-of-month fuel stocks.
EIA-767	Formerly, FPC Form 67. Annual, mandatory data collection for 779 utilities (plants >100 MW). Unit level data on consumption, generation, and operation.
Electric Utility Unit Inventory	1980 data base of all electric utility power plants. Provides unit level SO_2 emissions, unit data, fuel data, and control equipment information.
Electrical World	Annual data collection of all utilities. Provides inventory data and some unit specifics such as generating capacity and heat rates.
FERC-423	Formerly, FPC Form 423. Monthly, mandatory data collection for 300 utilities. Provides respondent ID, fuel type, contract, specifications, and costs.
Flue Gas Desulfurization Information System	Voluntary data collection from utilities equipped with FGD systems. Detailed information of FGD design, operation, and performance; unit level fuel and boiler data.
Generating Unit Reference File	Annual data collection for all utilities (>25 MW). Unit level data on capacity, fuel type, retirement/online status.
National Coal Association-Steam Electric Plant Factors	Annual data collection report for all utility plants. Provides fuel consumption, characteristics, and costs.
National Electric Reliability Council (NERC EP-411)	Annual, mandatory data collection for all utilities. Provides summer and winter peak net capability by unit, also primary and secondary fuel.

SECTION 3
CONTROL TECHNOLOGY PERFORMANCE AND COST BASES

Most existing studies analyzing the economic impact of the various acid rain congressional bills focus on two commercially demonstrated emission control technologies: FGD and coal switching. Two reports reviewed the potential applicability of the LIMB technology. [6, 7] However, neither of these reports rigorously evaluated the applicability of LIMB relative to recent advances in the technology or its suitability to particular types of boilers. The following sections describe the methodology used to develop the control technology costs used in this study and the methodology used to examine the applicability of LIMB to the coal-fired boiler population.

CONTROL TECHNOLOGY PERFORMANCE/COST

Three coal-fired boiler SO_2 reduction technologies were examined in this study:

- Limestone FGD with 90 percent SO_2 control,
- LIMB with 50/60 percent SO_2 control and 50 percent NO_x control, and
- Coal switching to a 2.5 pound of SO_2 per million Btu eastern bituminous coal.

Boiler specific costs for FGD and LIMB were provided by PEI Associates using the IAPCS-2 computer model [8]. Table 3-1 summarizes the cost/performance assumptions used to make the computer runs. Appendix A presents additional information about the procedures used to generate costs for each boiler.

The cost of coal switching was based on a coal cost differential of $1.00 per million BTU above the current higher sulfur coal. Although boiler specific costs for high and low sulfur coals were available, due to the current soft market, several plants are actually obtaining low sulfur coal at prices below high sulfur coal. This is not anticipated to be the case if many plants were required to switch coals because the added demand for low sulfur coal would drive up its price relative to high sulfur coals.

TABLE 3-1. PERFORMANCE AND COST PARAMETERS USED TO ESTIMATE FGD AND LIMB ANNUALIZED COSTS AND EMISSION REDUCTIONS

LIMB PERFORMANCE PARAMETERS

50 Percent LIMB Cases	60 Percent LIMB Cases
50% SO_2 Reduction	60% SO_2 Reduction
50% NO_x Reduction	50% NO_x Reduction
Calcitic Hydrate	Calcitic Hydrate
2.5:1 Ca/S Ratio	3:1 Ca/S Ratio
700^{o}F Quench Rate	700^{o}F Quench Rate

ESP upgrade and SO_3 conditioning for control of additional particulate matter

FGD PERFORMANCE PARAMETERS

90% SO_2 Reduction and No NO_x Reduction

Limestone Slurry Sorbent

No Spare Absorbers

Number of Absorber Towers Based on Boiler Size

< 100 MW - 1

100 MW to 250 MW - 2

250 MW to 500 MW - 3

500 MW to 750 MW - 4

> 750 MW - 5

GENERAL COST BASES

EPRI Cost Premises Used (see Appendix A)

Costs are in 1995 Dollars

Equipment Book Life of 15 Years

FGD Retrofit Difficult Factor of 1.2 Times New Plant Cost

The cost difference for low versus high sulfur coal of $1.00 per million Btu compares with the coal price differential predicted by other studies and the estimated cost of deep physical coal cleaning. [9] It was assumed that most of the plants would not switch to low sulfur western sub-bituminous coals due to the high transportation costs, technological problems, and or the negative cost impacts of burning coals with significantly lower Btu contents.

CONTROL TECHNOLOGY APPLICABILITY

For each control technology, boiler applicability was determined based on technical considerations and secondly on cost. Table 3-2 summarizes the boiler population constraints developed for the three technologies considered under this study.

TABLE 3-2. BOILER SPECIFIC CONTROL TECHNOLOGY APPLICABILITY

Boiler Parameter	LIMB	Wet FGD	Coal Switching
Firing Type	Pulverized Coal Only	Pulverized Coal and Cyclone	Pulverized Coal and Cyclone
Optimum Sulfur Level $lbs/10^6$	1.2 to 6.0	> 1.2	> 2.5
Boiler Service Date	≥ 1960	≥ 1965	1950 - 1959
Boiler Size	> 50 MW	> 50 MW	Any Size

Boiler firing type restrictions for LIMB were based on the current development goals directed at wall and tangential fired boilers.[10] FGD and coal switching were not restricted based on firing type although coal switching at slagging type boilers would be restricted to those coals with proper ash fusion properties.

No technologies were applied to boilers with SO_2 emissions less than 1.2 pounds per million Btu's, because these boilers would not be required to reduce emissions. Coal switching was applied only to boilers whose current

sulfur emissions were higher than would be achieved by the switch coal used in this study. The LIMB technology was not applied to boilers having high emission rates (> 6.0 pounds SO_2 per million Btu) because in the boiler age range considered (post 1960 boilers) these larger, high sulfur plants would generally be very cost effective applications for FGD.[11]

The boiler service year applicability are based on a boiler life of 45 years. Boilers with less than 10 years of remaining life (1950 to 1959) were assumed to coal switch. LIMB was assumed to be applied to boilers having at least 10 years of remaining service life ($\geq$ 1960). FGD was assumed not to be applied to boilers with less than 15 years of service life due to the high rate of capital recovery required for pay back periods of less than 15 years.[11]

LIMB and FGD were not applied to boilers smaller than 50 MW. This is due to model cost algorithm limitations for small boilers.

Two additional factors that were incorporated into the analysis involved the emission reduction impacts of boiler retirement and the retrofit of FGD units on boilers installed since 1980. This study assumed that all boilers with service dates prior to 1950 would be retired or put on stand-by status by 1995. An SO_2 emission reduction credit was taken which assumed that pre-1950's boiler capacity was replaced by coal-fired boilers complying with the 1971 NSPS (1.2 lbs. SO_2 per million Btus). Additional SO_2 reduction credits were also taken for those boilers which have already installed FGD systems since 1980. For these boilers, a 90 percent emission reduction credit was assumed. The total amount of emission reduction achieved from these retired and recently FGD equipped boilers was 552,000 tons per year of SO_2.

SECTION 4
RESULTS AND CONCLUSIONS

As described in Section 2, a number of cases were run to determine the applicability of the LIMB technology for various legislative strategies. A computer model developed by Radian was used to determine for each regulatory case, the mix of control technologies needed to achieve the necessary emission reductions. Each computer run provides a separate estimate of the potential application of LIMB technology into the coal-fired boiler population. Total annualized costs for each regulatory case were developed using boiler specific control costs provided by PEI Associates.

METHODOLOGY

Table 4-1 presents the methodology used in determining the control technology mix for each regulatory case. This methodology prioritizes the application of each technology based on the legislative analysis, technical constraints and emission reduction targets to estimate the maximum LIMB applicability. For all cases, emission reductions were obtained first by taking credit for retiring pre-1950's boilers and application of FGD to boilers that since 1980 have retrofit FGD.

Boiler Performance Standard

Two cases run for the boiler performance standard legislative strategy provide an upper and lower bound on the amount of LIMB which would be used to achieve the desired SO_2 reductions. In the first case, FGD was applied to every (post-1965 service year) boiler in the top 50 SO_2 emitting power plants. LIMB was then applied to all remaining boilers considered technically applicable (post 1960 wall/tangential fired boilers with sulfur emissions between 1.2 and 6.0 lbs/million Btu). Coal switching was then added to the 1950's boilers until the emission reduction target of 7.2 million tons per year of SO_2 was reached.

For the second case of this regulatory scenario, coal switching was applied before LIMB. Because coal switching on the 1950's boilers can achieve the required emission reduction target, no LIMB was applied.

TABLE 4-1. CONTROL TECHNOLOGY MIX FOR EACH REGULATORY CASE

Regulatory Case	Early Retirement and Post 1980 FGD	Second Priority	Third Priority	Fourth Priority	Totals	Levelized Annual Cost[a] 1995 $ x 10^9
Boiler Performance Case - MAX LIMB		FGD-Top 50	LIMB-50%	Coal Switch 1950's units		
MW of Application	6,731	69,428	13,446	2,991	92,596	14.0
Emission Reduction (10^3 Tons/yr)	553	5,553	646	460	7,212	
Boiler Performance Case - MAX CS		FGD-Top 50	Coal Switch 1950's units	-		
MW of Application	6,731	69,428	8,374	-	84,533	12.9
Emission Reduction (10^3 Tons/yr)	553	5,553	1,096	-	7,202	
Regional Reduction Case - MAX LIMB		LIMB-50%	FGD:cyclones and high S coal	Coal Switch 1950's units		
MW of Application	6,731	70,888	14,781	11,212	103,612	9.9
Emission Reduction (10^3 Tons/yr)	554	3,533	1,883	1,247	7,217	
Regional Reduction Case - MAX Coal Switch		Coal Switch 1950's units	FGD:cyclones and high S coal	LIMB-50		
MW of Application	6,731	24,853	14,781	65,490	111,855	10.1
Emission Reduction (10^3 Tons/yr)	554	1,544	1,883	3,267	7,248	
Regional Reduction Case - 60% LIMB		LIMB-60%	Coal Switch 1950's units	FGD:cyclones and high S coal		
MW of Application	6,731	70,888	24,853	8,504	110,976	11.4
Emission Reduction (10^3 Tons/yr)	554	4,154	1,544	1,087	7,339	
Regional Reduction Case - 5.9 MT/yr Reduction		LIMB-50%	Coal Switch 1950's units	FGD:cyclones and high S coal		
MW of Application	6,731	70,888	24,853	3,191	105,663	8.3
Emission Reduction (10^3 Tons/yr)	554	3,533	1,544	347	5,978	
Regional Reduction Case - 8.5 MT/yr Reduction		LIMB-50%	FGD	Coal Switch		
MW of Application	6,731	38,444	50,230	25,206	120,611	14.3
Emission Reduction (10^3 Tons/yr)	554	1,976	4,313	1,665	8,508	

Regional Reduction Regulatory Cases

Five different cases were run under this legislative scenario. Three of these cases are related to the three different SO_2 reduction scenarios (8, 10 and 12 million tons per year). The other two cases look at the impact of high performance LIMB (60% SO_2 reduction) and the impact of maximizing coal switching.

In the Maximum (MAX) LIMB case, LIMB was applied first to the applicable boilers (post 1960 wall/tangential fired boilers with SO_2 emission levels between 1.2 and 6.0 pounds/million Btu). Then, FGD was applied to cyclone fired boilers and boilers with SO_2 emissions greater than 6.0 lbs per million Btus. Finally, coal switching was applied to 1950's boilers until the target reduction level was reached. As a result half of the boiler population is controlled with the LIMB technology and the application of coal switching and FGD were minimized.

For the second 10 million ton reduction case, coal switching was maximized by applying it first to all the 1950's boilers. For this case, FGD was held the same as for the MAX LIMB case and LIMB was then applied to achieve the target 7.2 million ton reduction level. This case results in a slightly lowered application of LIMB.

For the third 10 million ton per year reduction case, high performance (60% SO_2 reduction) LIMB was applied, followed by FGD and coal switching as in the Max LIMB case. This case lowers the penetration of FGD due to the greater SO_2 reduction achieved by the high performance LIMB technology.

For the 8 million ton per year emission reduction case, coal switching to the 1950's boilers was applied first followed by LIMB and FGD. For this case very little FGD is required to achieve the 5.8 million tons per year of SO_2 reduction.

For the 12 million ton per year reduction case, the application of LIMB can not be maximized if the reduction target is to be achieved. For this case the application of LIMB was reduced by increasing the use of FGD on these boilers and allowing all remaining uncontrolled boilers to be coal switched. This case results in almost all boilers being controlled to attain the top 100 plant emission reduction level of 8.5 million tons of SO_2.

DISCUSSION OF RESULTS

Figures 4-1 and 4-2 summarize the results of the 10 million ton per year SO_2 reduction cases. Figures 4-3 and 4-4 summarize the results of the 8, 10 and 12 million ton per year SO_2 reduction cases. The results of these analyses are discussed below.

10 Million Ton Per Year SO_2 Reduction Cases

Figure 4-1 summarizes the results of the 10 million ton per year SO_2 reduction cases. Two cases were run for the Boiler Performance Standard strategy to provide an upper and lower bound on the amount of LIMB which would be used to achieve the desired SO_2 reductions. In the first case, FGD was applied to the boilers in the top 50 SO_2 emitting power plants with post 1965 service year achieving over 5.5 million tons per year of SO_2 reduction. LIMB was applied to the remaining boilers which were considered technically applicable (post 1960 wall/tangential fired boilers with sulfur emissions between 1.2 and 6.0 lbs/million Btu). This case results in 69,000 MW of FGD application, 13,000 MW of LIMB application and 3,000 MW of coal switching.

For the second Boiler Performance Standard case, coal switching (MAX CS) was applied before LIMB resulting in 8,400 MW of coal switching. Because coal switching can be achieved on the 1950's boiler to meet the required emission reduction target, no LIMB was applied.

A previous study funded by EPA evaluating this regulatory case achieved 7.8 million tons per year of SO_2 reductions by applying FGD to the top 50 SO_2 emitting utility power plants.[2] This higher reduction level occurs because all boilers regardless of age were assumed to be retrofit with FGD. This level of SO_2 reduction by FGD also results in no need for the application of the LIMB technology to achieve the SO_2 reductions appropriated to the top 100 plants. Removal of the boiler age constraint (no FGD on pre-1965 boilers) for this study would have resulted in an SO_2 emission reduction of 7.4 million tons per year. The emission reduction level differs slightly due to the use of different boiler emission data bases and assumptions regarding unit retirement and post-1980 FGD emission reductions to meet SIP.

Three different cases were run for the 10 million ton per year regional allocation scenario. The first two cases provided an upper and lower bound

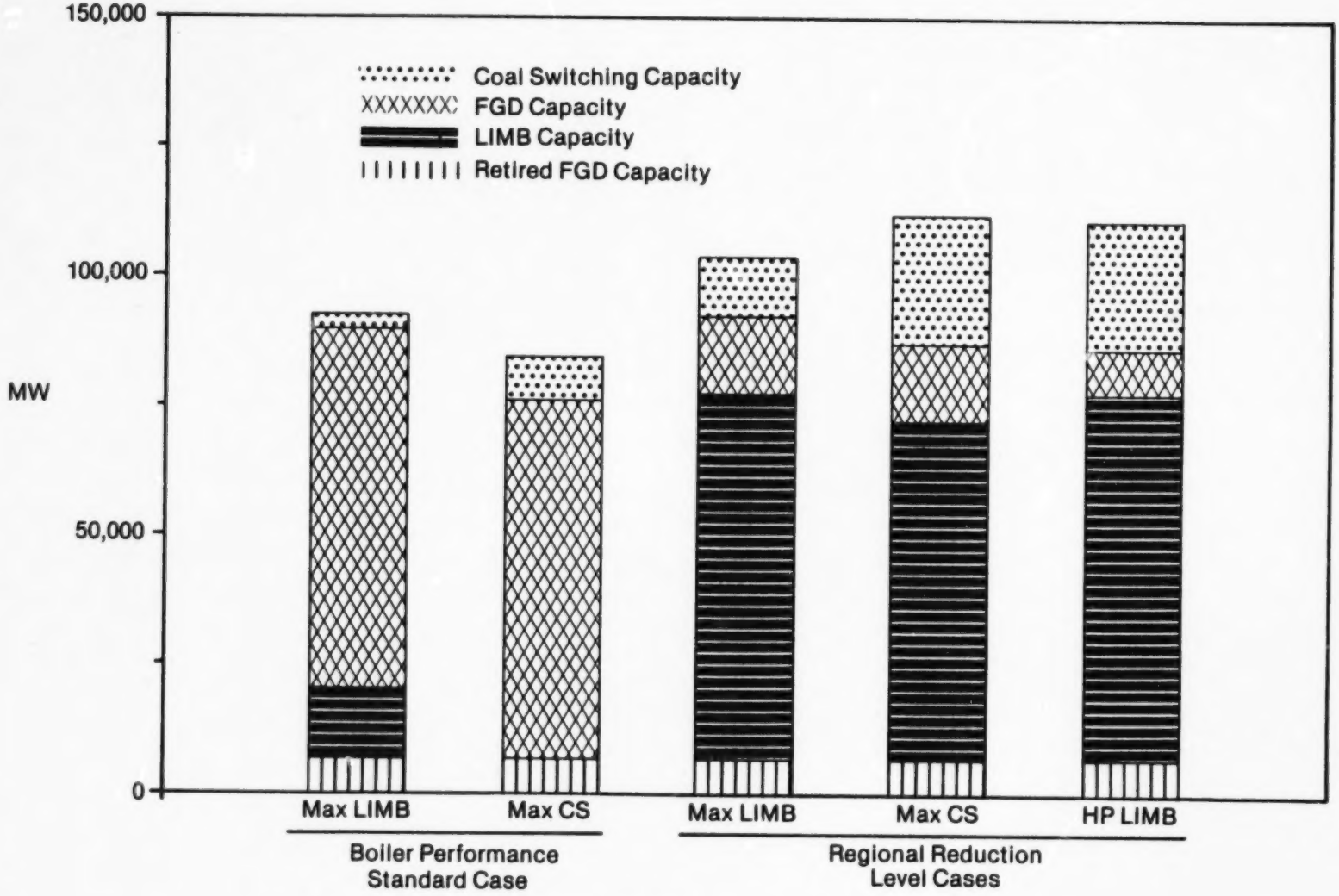

Figure 4 - 1. Boiler application results for 10 million tons per year of SO_2 reductions

on the amount of LIMB which would be used versus coal switching. The other case looks at the impact of high performance (HP) LIMB (60% SO_2 reduction). For the maximum (MAX) LIMB case, LIMB was applied first to the applicable boilers resulting in half of the boiler population (71,000 MW) being controlled with the LIMB technology, 15,000 MW of FGD and 11,000 MW of coal switching.

For the second 10 million ton reduction case, coal switching was maximized (MAX CS) by applying it first to all the 1950's boilers. For this case FGD was held the ame as for the MAX LIMB case and LIMB was then applied to achieve the target 7.2 million ton reduction level. This reduces LIMB application to 65,000 MW and increases coal switching to 25,000 MW of application. For the third 10 million ton per year reduction case, high performance (60% SO_2 reduction) LIMB was applied, followed by FGD and coal switching as in the MAX LIMB case. This case decreases the penetration of FGD due to the greater SO_2 reduction achieved by high performance (HP) LIMB technology. Although, the application of LIMB remains at 71,000 MW, the emission reduction increases from 3.5 million tons per year to 4.2 million tons per year of SO_2 and 1/2 NO_x.

Figure 4-2 summarizes the cost results in the five 10 million ton per year SO_2 reduction cases. The boiler performance standard cases have the highest annual control cost of 13 to 14 billion dollars per year due to the large number of boilers which must apply FGD. The regional annual costs of the regional reduction level cases are significantly lower and range from 9.9 to 11.7 billion dollars per year due to the greater use of coal switching and LIMB. Appendix B summarizes the average cost of applying FGD and LIMB to the applicable top 100 plant and 31 eastern state boiler population.

8, 10 and 12 Million Ton Per Year Cases

Figure 4-3 presents the results analyzing the impact of various emission reduction scenarios on the application of LIMB. The 10 million ton per year SO_2 reduction case is the same as for the Max LIMB regional allocation case discussed above. For this case, 71,000 MW of LIMB was applied to achieve the emission reduction target.

For the 8 million ton per year reduction case, coal switching to the 1950's boilers was applied first (lowest unit cost) followed by LIMB and FGD

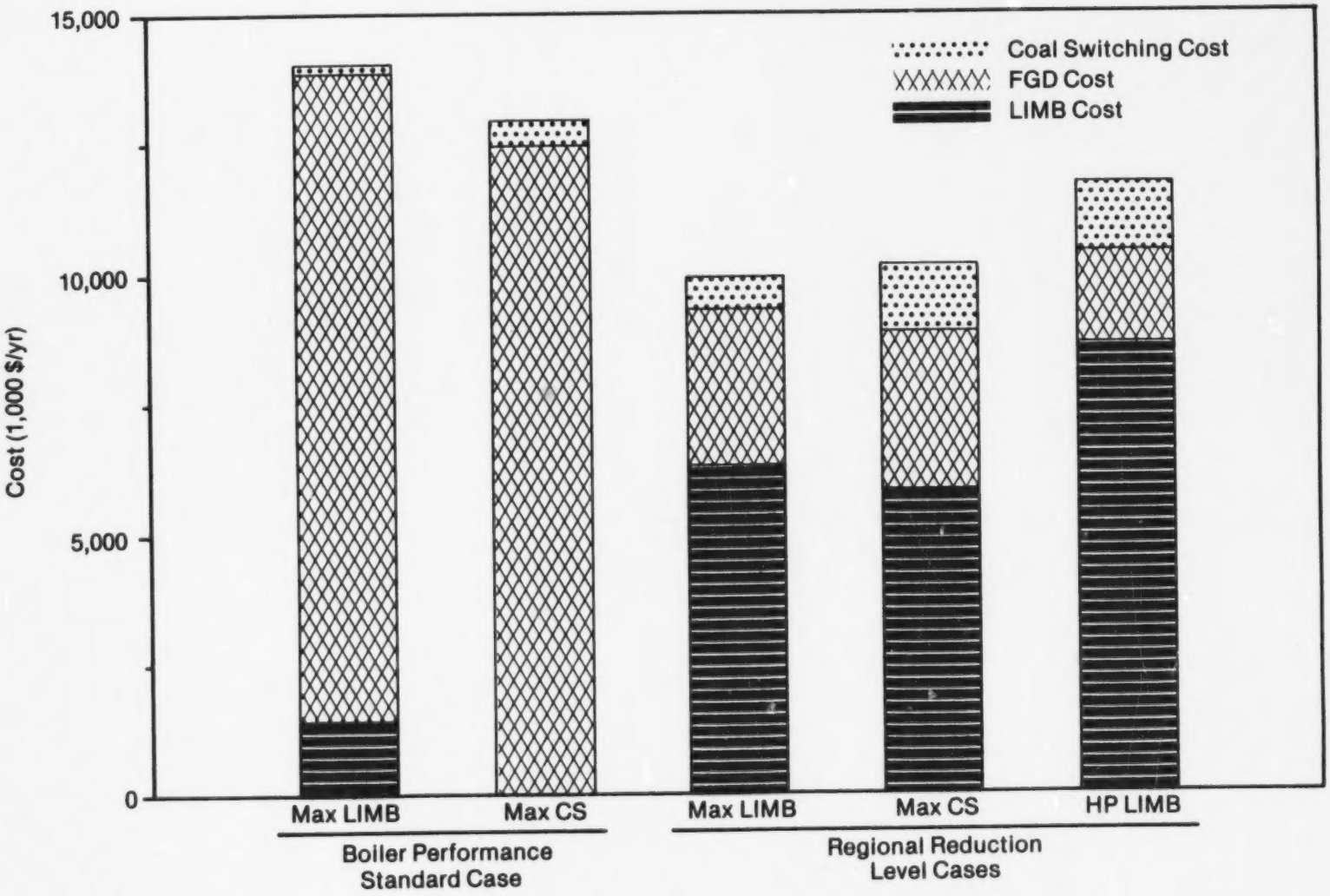

Figure 4 - 2. Levelized annual cost of control (1995 $)

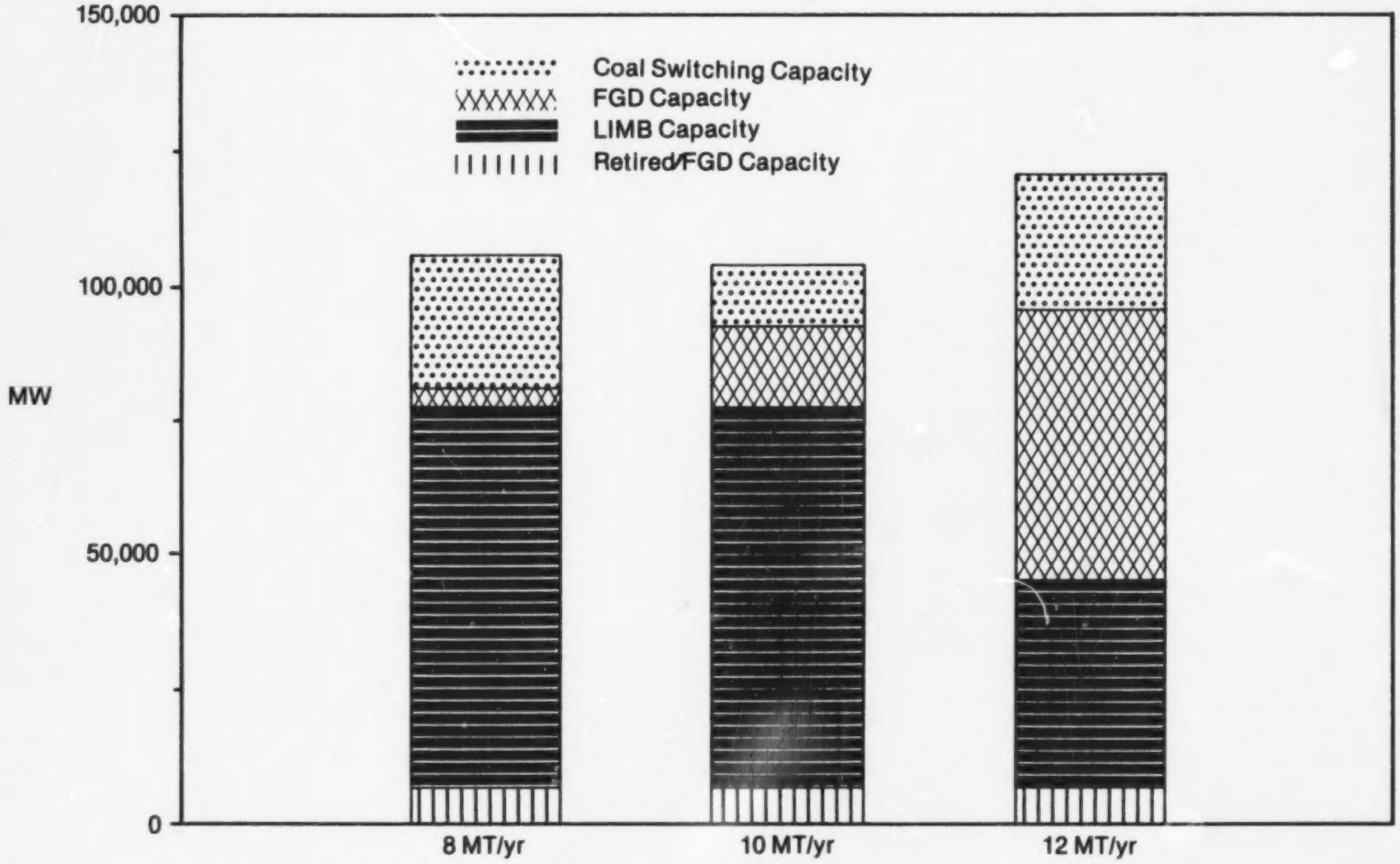

Figure 4 - 3. Boiler application results for 8, 10 and 12 million tons per year cases

to achieve the emission reduction target. This results in boiler application of 71,000 MW of LIMB, 25,000 MW of coal switching and 3,200 MW of FGD.

For the 12 million ton per year emission reduction case, the application of LIMB cannot be maximized if the emission reduction target is to be achieved. For this case, LIMB application was reduced by increasing the use of FGD and allowing all boilers where FGD and LIMB were not applied to coal switch. This results in the following boiler applications: 38,000 MW of LIMB, 50,000 MW of FGD and 25,000 MW of coal switching.

Figure 4-4 presents the annual cost for the three cases. The annual costs and unit costs increase significantly as the emission reduction levels increase over 10 million tons per year as shown below:

Annual Reduction 10^6 Tons Per Year	% Increase Emission Reduction	% Increase in Cost	Average Unit Cost $/ton
8	--	--	1381
10	25	23	1397
12	50	73	1678

These cost increases are due to the significantly increased application of FGD needed to obtain the very high overall average emission reductions per boiler/plant.

31 Eastern State Region

To estimate the potential LIMB applicability for all of the coal-fired boilers in the 31 eastern state region, the number of boilers in that region that fit the LIMB and FGD technical applicability presented in Table 3-2 was determined by PEI Associates from the 31 eastern state utility boiler data base. The amount of capacity for which LIMB was applicable was 103,000 MW. The amount of FGD capacity for this boiler population was 108,000 MW.

The average unit cost of applying LIMB and FGD to the applicable boilers not in the top 100 plants is significantly greater. This occurs because these boilers are smaller, have lower capacity factors, and fire lower sulfur coals. The following table summarizes some of the average

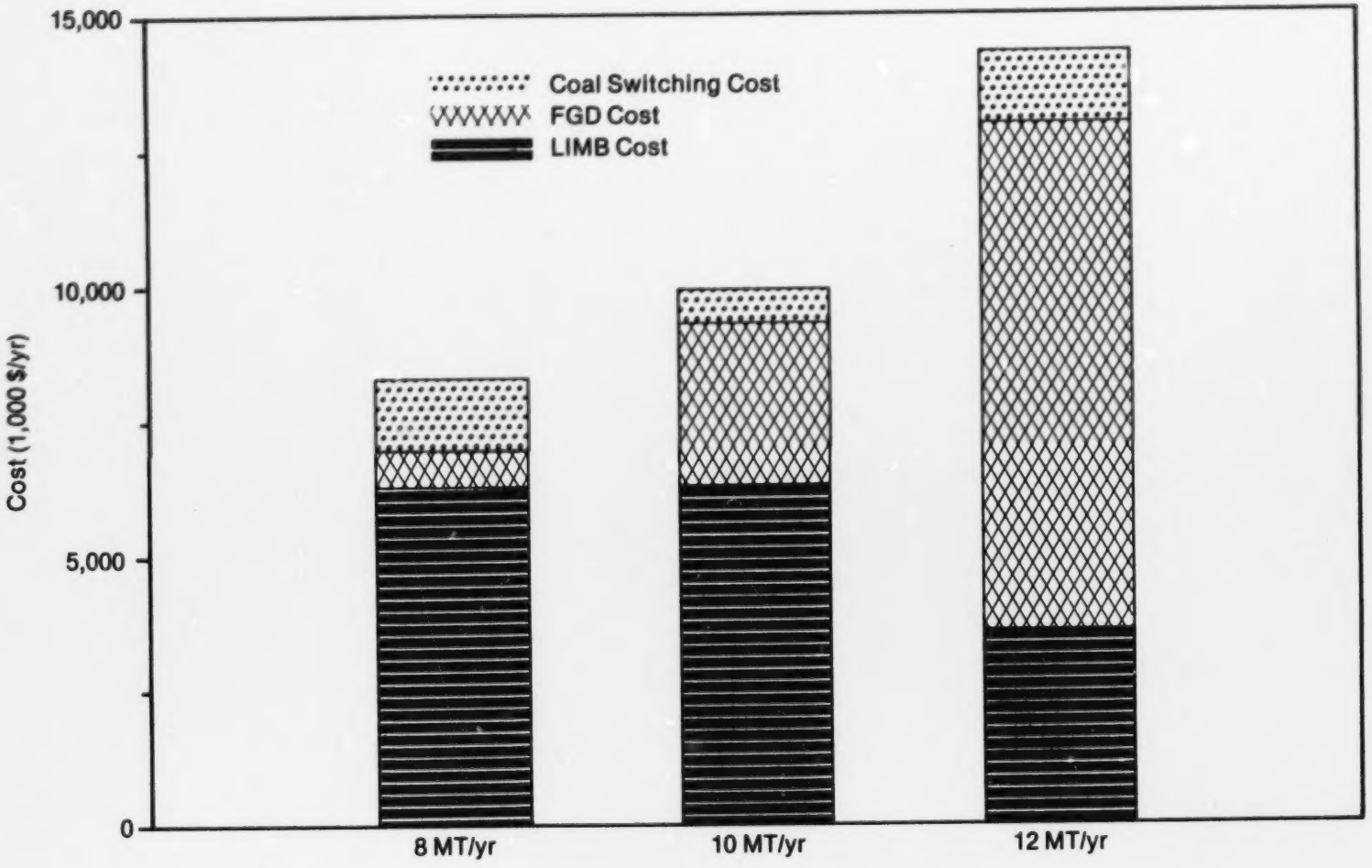

Figure 4 - 4. Levelized annual cost of control for 8, 10 and 12 million tons per year cases (1995 $)

characteristics of the top 100 plant boilers as compared to the remaining 31 eastern state coal-fired boilers.

Average Characteristics	Top 100	Remaining 31 State
Number of Boilers	379	600
Boiler Age - Years	22	24
Boiler Size - MW	357	157
Boiler Capacity - %	57	44
Coal Sulfur - %	2.5	1.8
50% LIMB Average Unit Cost - $/Ton	1804	2547
FGD Average Unit Cost - $/Ton	1007	3451

Although coal switching would be the most cost effective method of SO_2 control as discussed previously, the lower average coal sulfur content of the boiler population means that a 0.95 percent sulfur coal would be needed at all boilers to achieve the average reduction level of 47%. This would result in over 100 million tons of coal switching. Therefore, the LIMB technology would appear to be very attractive because of its lower overall unit cost versus FGD for this boiler population and its ability to obtain higher SO_2 reduction levels than coal switching. This means that the maximum LIMB applicability potential for the 10 million ton per year SO_2 reduction strategy not mandating the use of FGD could be as high as 100,000 MW of boiler capacity.

CONCLUSIONS

This study focused on identifying the maximum potential applicability of the LIMB technology based on currently anticipated technology constraints to boiler types defined by coal sulfur, firing type and age. A true optimization of the control technology mix based on cost was not conducted. However, the study results were compared to other studies in which cost optimizations were conducted. Two 1983 reports prepared for EPA [6, 12] estimated the potential application of the LIMB technology to be between

15,000 and 57,000 MW for a 10 million ton per year SO_2 reduction scenario similar to this study's regional allocation strategy. The study predicted that between 123 and 78 million tons of low sulfur coal switching would occur, respectively to the amount of LIMB application. The amount of coal switching allowed under this study ranged from 25 to 55 million tons per year. Other studies also predict that legislation similar to the boiler performance standard cases in this study, will be much more costly than the regional reduction legislative scenarios [13, 14]

In conclusion, this study indicates up to 100,000 MW of boiler capacity where LIMB application is possible depending upon the type of acid rain legislation adopted and the amount of coal switching which is economically and politically practical. Legislative strategies requiring SO_2 reductions of 8-10 million tons per year will maximize the application of LIMB because it is anticipated to be more cost effective than FGD. Control strategies requiring levels of SO_2 reductions greater than 10 million tons per year will decrease the application of LIMB. This occurs because the average level of SO_2 control required at each boiler would exceed that available with a broad application of LIMB. Control strategies which would require high levels of control (>60%) at each boiler would also reduce the application of LIMB unless combined with fuel substitution.

After this study was essentially complete, two new congressional bills were proposed in the second session of the 99th Congress. House of Representatives Bill HR-4567 would require that the following utility boiler fossil fuel emission levels be achieved by each state:

- state average emission level of 2.0 pounds per million of SO_2 by 1993 and,
- state average emission levels of 1.2 pounds per million of SO_2 and 0.6 pounds per million of NO_x by 1997.

Senate Bill S-2203 would require that each fossil fuel fired utility boiler reduce emission levels to 0.7 pounds per million of SO_2 by 1991 and that any utility boiler greater than 35 years of age must comply with the current new source performance standard.

A detailed analysis of these bills was not conducted under this study but both bills would require a high level of control for the top 100 coal-fired utility boilers. Thus, it is anticipated that the applicability of 50% LIMB to be similar to the boiler performance standard regulatory cases. However, additional evaluation should be conducted to evaluate the impact of increasing LIMB SO_2 reduction performance levels above 60 percent consistent with ongoing LIMB research and development goals.

SECTION 5
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Appendix A. Integrated Air Pollution Control System Version II Cost Bases

COST FORMATS

Pollution control cost estimates must be comparable in terms of base year dollars, cost categories, and overall content (i.e., cost components). To facilitate comparisons, IAPCS2 has adopted the bases and format of cost estimation used by the Tennessee Valley Authority (TVA) and the Electric Power Research Institute (EPRI), which are generally accepted as standardized cost-estimating formats.

CAPITAL COST FORMATS

The format for the direct component (i.e., installed equipment costs) of the capital costs will entail one or several line items for each of the control modules in a given control configuration. Major components for a given module will be itemized; the level of presentation will vary from one-line item (e.g., SH) to three-line items (e.g., FGD).

Indirect components, which are an integral part of capital cost estimates, are standardized and presented at the system level in IAPCS2. The two formats, TVA and EPRI, are presented in Tables 1 and 2, respectively.

Interpretation of the TVA and EPRI guidelines resulted in the assignment of percentages within IAPCS2 for each of the indirect components for each of the control modules. The TVA indirect costs are calculated as percentages of the Total Direct Investment (except for contingency, working capital, interest during instruction, and allowance for startup and modifications). The values assigned to these indirect components are presented in Table 3.

The EPRI indirect costs are calculated as a percentage of the Process Capital Cost (except for the preproduction costs, inventory capital, and land). The IAPCS2 values for indirect costs in the EPRI format are provided in Table 4.

ANNUAL COST FORMATS

As in the case of capital cost estimates, TVA and EPRI use different formats and bases to present annual costs. Table 5 presents TVA's format

and Table 6 presents EPRI's format. Each format stops short of providing the particular method and line item components used for levelling the costs. These procedures are described later.

The maintenance, labor, and materials estimated by the TVA format for a given system are actually percentages of the Total Direct Costs rather than man-hours and actual material estimates for FGD. This idea was expanded to include all IAPCS2 modules; the percentages used are presented in Table 7.

These same percentages are used to estimate maintenance, labor, and materials in the EPRI format. The number is distributed as 40 percent labor and 60 percent materials, and the labor man-hours are back-calculated.

In the EPRI format, annual O&M costs are presented as a fixed and variable component. Equations presented in the EPRI-TAG document provide the basis for calculating these components.

UNIT COSTS

Costs of labor, certain materials, reagents and chemicals, and waste disposal must be specified in any cost estimate. Table 8 provides the bases used for TVA and EPRI cost formats. Calculations performed by IAPCS2 yield the quantities of labor, materials, and waste generated by a specific configuration, and unit costs are applied to estimate the annual cost.

TABLE 1. TVA INDIRECT CAPITAL INVESTMENT COMPONENTS

Indirect Investment

Engineering design and supervision
Architect and engineering contractor
Construction expense
Contractor fees
Contingency
Disposal area indirects

Total fixed investment

Other Capital Investment

Allowance for startup and modifications
Interest during construction
Royalties
Land
Working Capital

Total capital investment

TABLE 2. EPRI INDIRECT COST FORMAT AS APPLIED TO IAPCS2

General Facilities
Engineering/Home Office
Project Contingency
Process Contingency
Sales Tax

Total Plant Cost

Royalty Allowance
Preproduction Costs
Inventory Capital
Initial Catalyst
Land

Total Capital Requirement

TABLE 3. TVA INDIRECT COST FORMAT APPLIED TO CONTROL MODULES IN IAPCS
(Percentage of Total Direct Investment (TDI), except as noted)

Indirect Component	LNB/OFA	LIMB	FGD	LSD	DSI	SH	ESP	FF
Engineering design and Supervision	6	8	6-8	7	6	6	6	6
Architect and engineering contractor	1	3	1-3	2	1	1	1	1
Construction expense	14	18	14-18	16	14	14	14	14
Contractor fees	4	6	4-6	5	4	4	4	4
Contingency[a]	20	20	10	20	20	20	20	20
Total (% of TDI)	50	62	37.5-	56	50	50	50	50
Royalties	0	0	0	0	0	0	0	0
Working capital	b	b	b	b	b	b	b	b
Interest during construction	4.84[d]	4.84[d]	15.6[c]	15.6[c]	4.84[d]	4.84[d]	15.6[c]	15.6[c]
Allowance for startup and modifications[e]	10	10	8	10	10	10	10	10
Land[f]	NA	$4700/ acre	$4700/ acre	$4700/ acre	$4700/ acre	NA	$4700/ acre	$4700/ acre

[a]Percent of direct plus indirect

[b]1 month of raw materials
1.5 months ov conversion costs
1.5 months of plant and administrative overhead
3% of total direct investment

[c]Assumes 3-year construction schedule

NA - Not Applicable

[d]Assumes 1-year construction schedule

[e]Percentage of direct plus indirect plus contingency

[f]TVA's $6000/acre (1985 dollars) deescalated by 8-1/2% per year

TABLE 4. EPRI INDIRECT COST FORMAT APPLIED TO THE CONTROL MODULES IN IAPCS
(Percentage of process capital cost, expected as noted)

Indirect Component	LNB/OFA	LIMB	FGD	LSD	DSI	SH	ESP	FF
General facilities	10	10	10	10	10	10	10	10
Engineering and home office fees	10	10	10	10	10	10	10	10
Project contingency	15	30	15	15	20	20	15	15
Process contingency	10	30	10	15	20	20	10	10
Sales tax	0	0	0	0	0	0	0	0
Total % of process capital	45	80	45	50	60	60	45	45
Royalty allowance	0	0	0	0	0	0	0	0
Preproduction costs	a	a	a	a	a	a	a	a
Inventory capital	b	b	b	b	b	b	b	b
Initial catalyst	0	0	0	0	0	0	0	0
Land[f]	NA	$6215/ acre	$6215/ acre	$6215/ acre	$6215/ acre	NA	$6215/ acre	$6215/ acre

[a] 1 month of fixed operating cost
1 month of variable operating cost
2% of total plant investment
Fuel cost (see text)

[b] 60-day supply of consumables

[c] $5500 in 1980 dollars escalated at 8.5%/yr = $6215 in mid-1982 dollars (based on EPRI's apparent escalation rate)

NA - Not Applicable

TABLE 5. TVA ANNUAL COST FORMAT

	Annual Quantity	Unit Cost, $	Total Annual Cost
Direct Costs - First Year			
Raw materials			
Limestone	tons	/ton	
Lime	tons	/ton	
Nahcolite	tons	/ton	
Conversion costs			
Operating labor and superivision			
System	man-hr	/man-hr	
Solids disposal facility	man-hr	/man-hr	
Solids disposal cost			
wet	tons	/ton	
dry	tons	/ton	
Utilities	tons	/ton	
Process water	10^3 gal	/10^3 gal	
Electricity	kWh	/kWh	
Reheat	10^6 Btu	/10^6 Btu	
Maintenance			
Labor and material			
Analysis	man-hr	/man-hr	
Total conversion costs			
Total direct costs			
Indirect Costs - First Year			
Overheads			
Plant and administrative			
Marketing (10% of byproduct sales)			
Byproduct credit	tons	/ton	
Total first-year operating and maintenance costs			

TABLE 6. EPRI ANNUAL COST FORMAT

	Annual Quantity	Unit Cost, $	Total Annual Cost	1st yr $/Kw-yr
Operating & maintenance costs				
Operating labor				
System	man-hr	/man-hr		
Solids disposal	man-hr	/man-hr		
Maintenance labor	man-hr	40%		
Maintenance material	$	60%		
Admin. & support labor	$	30% O&M		
Solids disposal cost				
wet	tons	/ton		
dry	tons	/ton		
Fixed component	$			
Variable component	$			mills/kWh
Consumables				
Limestone	tons	/ton		
Lime	tons	/ton		
Nahcolite	tons	/ton		
Water	10^3 gal	/10^3 gal		
Reheat	10^6 Btu	/10^6 Btu		
Electricity	kWh	mills/kWh		
Total O&M Costs				

TABLE 7. MAINTENANCE, LABOR, AND MATERIAL COST FACTORS

Maintenance, Labor, and materials	LNB/OFA	LIMB	FGD	LSD	DSI	SH	ESP	FF
TVA factors (% of Total Direct Investment)	2	4	7-9[a]	5-7[a]	4	2	4	4
EPRI factors (% of Total Process Capital)	2	4	8	6	4	2	4	4

[a]Decreasing from high to low with increasing boiler size from 200 to 1000 MW. For waste disposal, a fixed 3 percent of the waste disposal equipment plus construction cost is used.

TABLE 8. UNIT COSTS USED IN IAPCS2
(June 1982 Basis)

Item	TVA	EPRI
Lime, %/ton	64.30	47.47
Limestone, $/ton	7.29	13.56
Nahcolite, $/ton	-	-
ISI limestone	25	25
Calcitic quicklime	70	70
Dolomitic quicklime	75	75
Calcitic hydrate	70	70
Dolomitic hydrate	75	75
Operating labor, $/h	16.72[a]	17.24
Supervision labor, $/h	23.41[a,b]	20.69[c]
Maintenance labor, $/h	23.41[a,b]	17.24[c]
Maintenance supplies and materials (% of Direct Capital Cost)	7-9	1.5-10
Electricity, mills/kWh	31.7	39.8
Water, $/1000 gal	0.12	0.57
Waste disposal		
Wet, $/ton	-	11.64
Dry, $/ton	-	5.65
Overheat (plant)[d] % O&M Labor	30	30
Reheat, $/$10^6$ Btu	2.84	5.51

[a]Includes an additional 30 percent overhead burden for payroll.

[b]Equivalent to waste disposal or analysis labor rates.

[c]Estimated at 20 percent higher than operating labor.

[d]TVA uses an overall overhead of 60 percent; this item reflects an assumed plant overhead component only.

ECONOMICS

The IAPCS2 permits escalation and deescalation of the base year dollars for a given run. The system costs in 1982 dollars may be adjusted back to 1980 dollars or forward to 1990 dollars. Chemical Engineering cost indices are used to make these adjustments to the base year. The costs of labor, reagents and chemicals, and utilities also must be adjusted, as the startup year costs (first-year O&M costs) usually differ from costs during the first year of construction (capital costs).

Several cost components are used to annualize the O&M costs to include the capital component, and a single number representing a system cost may be used for comparative purposes. These factors include:

- Allowance for funds during construction
- Depreciation
- Annual interim replacement
- Insurance and property taxes
- Federal income and investment credit taxes

These can be combined into a levelized annual capital charge, as shown by TVA.

Appendix B. Top 100 and 31 Eastern State Plant Comparative Analysis

TOP 100 PLANT COAL-FIRED BOILERS
90% FGD TOTALS AND AVERAGES FOR SERVICE DATE > = 1965
AND UNCONTROLLED SO_2 EMISSIONS > = 1.2 LB/MM BTU

Boundary Condition(s)	Total	Average
# Companies	43	
# Plants	73	
# Units	151	
Name Plate Rating (MW)	88321	
Uncontrolled SO_2 Emissions (LB/MM BTU)		3.92
Controlled SO_2 Emissions (LB/MM BTU)		0.43
SO_2 Emissions Control (1000 Tons/Yr)	6396.6	
NO_x Emission Control (1000 Tons/Yr)	0.0	
PM Emissions Control (1000 Tons/Yr)	0.0	
Capital Cost $ Million Year	31178.8	
Capital Cost $/Kilowatt		387.58
Annual Cost (Levelized) $ Million Year	6439.5	
Annual Cost (Levelized) Mills/Kilowatt Hour		42.86
SO_2 Cost Effectiveness ($/Ton)		1007
NO_x Cost Effectiveness		0

31 EASTERN STATE COAL-FIRED BOILER
90% FGD TOTALS AND AVERAGES FOR SERVICE DATE > = 1965
AND UNCONTROLLED SO_2 EMISSIONS > = 1.2 LB/MM BTU

Boundary Condition(s)	Total	Average
# Companies	68	
# Plants	120	
# Units	218	
Name Plate Rating (MW)	108040	
Uncontrolled SO_2 Emissions (LB/MM BTU)		3.58
Controlled SO_2 Emissions (LB/MM BTU)		0.39
SO_2 Emissions Control (1000 Tons/Yr)	7474.7	
NO_x Emission Control (1000 Tons/Yr)	0.0	
PM Emissions Control (1000 Tons/Yr)	0.0	
Capital Cost $ Million Year	39397.9	
Capital Cost $/Kilowatt		423.54
Annual Cost (Levelized) $ Million Year	10159.7	
Annual Cost (Levelized) Mills/Kilowatt Hour		46.4
SO_2 Cost Effectiveness ($/Ton)		1359
NO_x Cost Effectiveness		0

TOP 100 PLANT COAL-FIRED BOILERS

50% LIMB TOTALS AND AVERAGES FOR SERVICE DATE > = 1960

UNCONTROLLED SO_2 EMISSIONS > = 1.2 LB/MM BTU AND ≤ 6.0 LB/MM BTU

Boundary Condition(s)	Total	Average
# Companies	38	
# Plants	60	
# Units	144	
Name Plate Rating (MW)	78558	
Uncontrolled SO_2 Emissions (LB/MM BTU)		3.40
Controlled SO_2 Emissions (LB/MM BTU)		1.62
SO_2 Emissions Control (1000 Tons/Yr)	3360.0	
NO_x Emission Control (1000 Tons/Yr)	949.9	
PM Emissions Control (1000 Tons/Yr)	0.0	
Capital Cost $ Million Year	13830.5	
Capital Cost $/Kilowatt		179.50
Annual Cost (Levelized) $/Million Year	6919.6	
Annual Cost (Levelized) Mills/Kilowatt Hour		19.93
SO_2 + .5 NO_x Unit Cost ($/Ton)		1804

31 EASTERN STATE COAL-FIRED BOILERS

50% LIMB TOTALS AND AVERAGES FOR SERVICE DATE >= 1960

UNCONTROLLED SO_2 EMISSIONS > = 1.2 LB/MM BTU AND $\leq$ 6.0 LB./MM BTU

Boundary Condition(s)	Total	Average
# Companies	65	
# Plants	122	
# Units	240	
Name Plate Rating (MW)	102948	
Uncontrolled SO_2 Emissions (LB/MM BTU)		3.01
Controlled SO_2 Emissions (LB/MM BTU)		1.44
SO_2 Emissions Control (1000 Tons/Yr)	4118.4	
NO_x Emission Control (1000 Tons/Yr)	1215.0	
PM Emissions Control (1000 Tons/Yr)	0.0	
Capital Cost $ Million Year	17814.0	
Capital Cost $/Kilowatt		179.39
Annual Cost (Levelized) $ Million Year	9188.7	
Annual Cost (Levelized) Mills/Kilowatt Hour		22.01
SO_2 + .5 NO_x Unit Cost ($/Ton)		1944